Chapter 6

THE ELECTRICITY SECTOR'S RESPONSE TO END-USE EFFICIENCY CHANGES

6.1 INTRODUCTION

Electricity consumption accounts for about 36% of both total primary energy consumption and carbon emissions in the United States (EIA 1996a). As a consequence, converting efficiency-induced electricity savings in the residential, commercial, and industrial sectors into carbon reductions is a critical part of this study.

This task is complicated by several factors. First, the U.S. electricity industry is in the midst of a major restructuring, from a highly regulated, vertically integrated industry to a largely competitive, deintegrated industry. Because this transformation is far from complete, it is difficult to predict the structure and operation characteristics of electricity markets for the year 2010. Second, electricity production in the year 2010 will depend on the generating units that are retired, repowered, and constructed between now and then, as well as on how those units are operated in 2010. The decisions made by the profit-maximizing owners of individual generating units are likely to be different than the cost-minimizing decisions made in the past by utility owners of large generation and transmission systems. As a result of these changing dynamics of capacity expansion and system operation, one cannot assume that the average and marginal carbon intensities of electricity use (tonnes of carbon/GWh) will be the same in 2010 as they are today. Indeed, they are likely to be quite different. Third, electricity prices in the year 2010 are likely to vary from hour to hour based on current spot-market prices; consumer response to such time-varying prices is likely to be substantial but is largely unknown.

The next section describes some of the key changes in the structure of the U.S. bulk-power system that are likely to occur over the next decade. Section 6.3 describes the Oak Ridge Competitive Electricity Dispatch (ORCED) model that is used here to project the characteristics of the electricity sector in the year 2010. Section 6.4 compares ORCED's projections for the electricity sector with those developed by EIA in its *Annual Energy Outlook 1997* (AEO97). We then develop a competitive-electricity market case for 2010, which is used as the base case against which the efficiency and high-efficiency/low-carbon cases are compared.

6.2 BACKGROUND

In response to the 1992 Energy Policy Act, the Federal Energy Regulatory Commission (FERC) issued a major order (Order 888) in April 1996, which it slightly revised in March 1997. This order requires utilities to unbundle their generation and transmission services. A utility cannot offer preferential transmission pricing for electricity generated by its own power plants. A key purpose of this order is to eliminate problems associated with vertical market power in bulk-power markets and thereby assure open access to the nation's transmission facilities.

Other factors are also forcing the U.S. electricity industry to change. These factors include low natural gas prices (both today and over the next 10 to 15 years), substantial improvements in the efficiency of gas-fired combustion turbines, and broad public sentiment to deregulate economic sectors wherever possible.

We see a future in which the generation sector will be driven primarily by competitive forces rather than by regulatory mandates. Decisions on whether, when, and where to build, repower, or retire generating units will be made by investors, not by regulators.[1] Historically, vertically integrated utilities have planned, built, and operated power plants to minimize the life-cycle costs of the entire electric-power system over a long time (e.g., 20- to 30-year horizon). In tomorrow's competitive environment, this decision rule will be replaced by one that emphasizes the profitability of individual generating units over a much shorter time horizon, using a higher discount rate to reflect the increased riskiness of power-plant ownership.

Our view of the future calls for most of today's utility-operated control centers to be replaced by *independent* system operators (ISOs) that cover larger areas. As a consequence, the number of control areas will decline from about 140 to perhaps only 20 to 50. Because these ISOs perform a monopoly function, they will be regulated by FERC.

Similarly, transmission will remain a monopoly function, also regulated by FERC. Increasingly, transmission will be separated from generation. Today, FERC requires utilities to "functionally" unbundle generation from transmission. In the future, utilities will increasingly divest themselves of their generation assets and will become "pure" transmission or transmission-plus-distribution utilities. In this environment, transmission will become a common carrier.

6.3 MODEL DESCRIPTION

ORCED is an expanded version of part of a previously developed model called ORFIN (Oak Ridge Financial Model) (Hadley 1996). Whereas ORFIN is a comprehensive electric-utility planning model, ORCED deals only with generation. We developed ORCED to aid in the analysis of the operation of competitive (as opposed to the traditional regulated) bulk-power markets. The model allows the following issues to be examined:

- Horizontal market power: concentration of generation assets among a few owners;

- Generator profitability: which units will be retired because their expected revenues will not cover the sum of their fuel costs, variable operations and maintenance (O&M) costs, and (avoidable) fixed O&M costs, as well as repowering and new construction decisions;

- Carbon emissions and other environmental effects of changes in the U.S. bulk-power sector; and

- Optimal mix of new and existing generators, including new generating technologies.

The model is structured to allow simulation of different bulk-power market structures. In particular, the user can specify various generation pricing schemes:

- An energy-only spot price as proposed by the three California investor-owned electric utilities. When unconstrained demand exceeds available supply, what would otherwise be unserved energy is "curtailed" because spot prices rise sufficiently to suppress demand to match the level of available generating capacity. The user simulates this situation by specifying a value for the price elasticity of demand during these time periods. ORCED uses the amount of demand to be curtailed and the price elasticity to calculate the value of unserved energy in ¢/kWh.[2]

- An energy-only spot price plus the loss-of-load probability (capacity) component used in the United Kingdom. Here, the user specifies a value for unserved energy (e.g., 200¢/kWh), which the model multiplies by the hourly value of the loss-of-load probability to produce a time-varying increment to the energy-only spot price.

- An energy-only spot price plus a capacity reservation price (in $/kW-year), as proposed by the PJM Interconnection and the New England Power Pool. In this case, the user specifies an amount of generating capacity needed for planning reserve, which determines the annual capacity payments (in $/kW-year) required.

We are using ORCED to examine the issues listed above as functions of the following factors (in addition to the pricing schemes noted above):

- Characteristics of individual generators: type of unit, differences in capital and other fixed costs ($/kW-year) vs. fuel and variable O&M costs (¢/kWh), dispatchability (e.g., fully dispatchable coal plant vs. must-run nuclear unit vs. stochastic wind plant), forced and planned outage rates (%).

- Customer and load characteristics: shape of load curve, price elasticities of demand, value of unserved energy.

- Generating-resource portfolio: mix of generating units and relationship between available generating capacity and unconstrained peak demand.

ORCED includes a production-costing model that uses load-duration curves rather than chronological loads as inputs. The model is run twice for each year of simulation, once for an on-peak season and a second time for an off-peak season (Figure 6.1). We define the on-peak season as June through August, and the off-peak season as the remaining nine months (September through May), although the model can accept alternative definitions of the two seasons. The model can incorporate disaggregate inputs on loads and load shapes for the residential, commercial, and industrial customer classes. Data on these class loads are aggregated for use within ORCED, which builds and dispatches generating units to meet aggregate load.

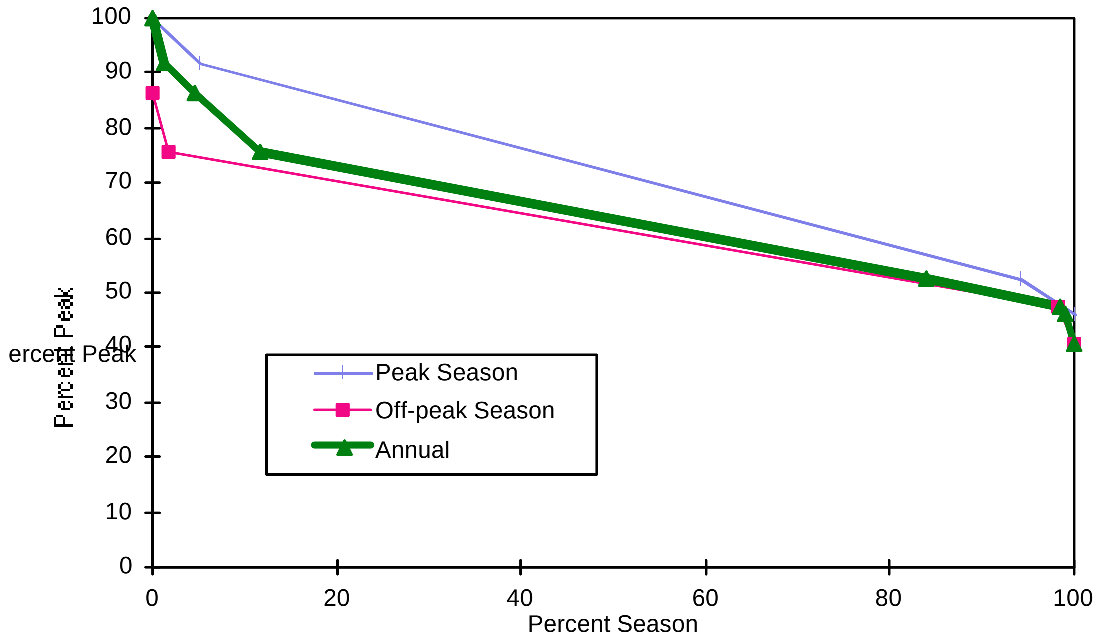
A load-duration curve is created by ordering demand (in MW) in terms of magnitude from highest to lowest. The resultant curve shows the percentage of time that demand exceeds a particular value, ranging from the one-hour peak demand down to the minimum demand.

Use of a load-duration curve to calculate production costs is much simpler and computationally much less burdensome than use of chronological loads (i.e., hour by hour loads). This simplification, however, has a price: because it obscures the timing of loads, one cannot accurately calculate production costs on the basis of generating-unit details, such as minimum and maximum loading points, startup times and costs, and minimum shutdown times. To partially remedy these problems, ORCED analyzes production costs using the two load-duration curves, one for the three-month summer peak period and the other for the nine-month off-peak period. ORCED also simulates the effects of startup costs for those units with capacity factors of less than 10%.

For each season, the model has available to it 26 generating units. The first 25 units are characterized in terms of capacity, forced and planned outage rates, fuel type, heat rate, variable O&M costs, fixed

O&M costs, and annual capital costs (based on initial construction cost, year of completion, and capitalization structure). The 26th unit is an energy-limited hydro unit, for which the inputs include, in addition to those noted above, the plant's capacity factor (equivalent to its maximum energy output for the year). This treatment of hydro as energy-limited ensures that hydro displaces the most expensive energy (i.e., at the top of the load-duration curves).

Figure 6.1 Example Load-Duration Curves for Peak and Off-Peak Seasons



The model dispatches these 26 generating units separately for the two seasons. Although the calculation process is the same for the two seasons, the results differ because of differences in the load-duration curves and because all the planned maintenance is assumed to occur in the off-peak season.

The plants are first dispatched against the load-duration curve on the basis of bid price, the default for which is variable (fuel plus variable O&M) costs. (If the user bids a zero price for a unit, the generator is treated as a must-run unit and is dispatched first by the model.) Because plants are not available 100% of the time, we also model forced outages on a probabilistic basis.[3] Thus, the higher-cost plants will see demands not only from customers, but "equivalent demands" based on the probability that plants lower in the dispatch order (i.e., less expensive) will be undergoing a forced outage. The model creates an equivalent load-duration curve for each plant, which extends the amount of time the plant runs based on the forced-outage rates of the plants lower in the dispatch order.

Model results include spot prices for each point on the two load-duration curves. These prices are based on the bid prices for each generator. The prices also reflect any externally imposed uplift charge, capacity charge, or emissions taxes. Finally, the prices during high-demand hours reflect generating-unit startup costs and the costs of unserved energy for those hours that unconstrained demand exceeds supply. See Appendix F for more details on the inputs and results from ORCED.

ORCED can be run iteratively to estimate the response of customers to changes in overall and time-of-use electricity prices. User inputs include an overall price elasticity of demand and a time-of-use elasticity. The overall price elasticity adjusts the entire load-duration curve up or down in response to decreases or increases in the average price of electricity. The time-of-use elasticity adjusts each point on the load-duration curve up or down based on price decreases or increases during that time period.

In addition, the model can use the time-of-use elasticity to compute the value of unserved energy (in ¢/kWh) that equilibrates supply and demand when unconstrained demand would otherwise exceed online supply. Alternatively, the user can input an estimate of the value of unserved energy, which is then used to calculate the costs associated with those times when unconstrained demand would exceed supply. A third approach involves user specification of a minimum reserve margin and associated annual capacity payment (in $/kW-year) to pay for this "extra" capacity.

In addition to dispatching power plants and computing production costs, the model can also "optimize" the mix of generating units available for the year of analysis. (That is, the model includes a capacity-expansion module as well as a production-costing module.) We put optimize in quotes because the factor on which to optimize is almost certain to be different for a competitive electricity industry than it was for the regulated electric utility industry. For example, the model could choose from among the following optimization functions:

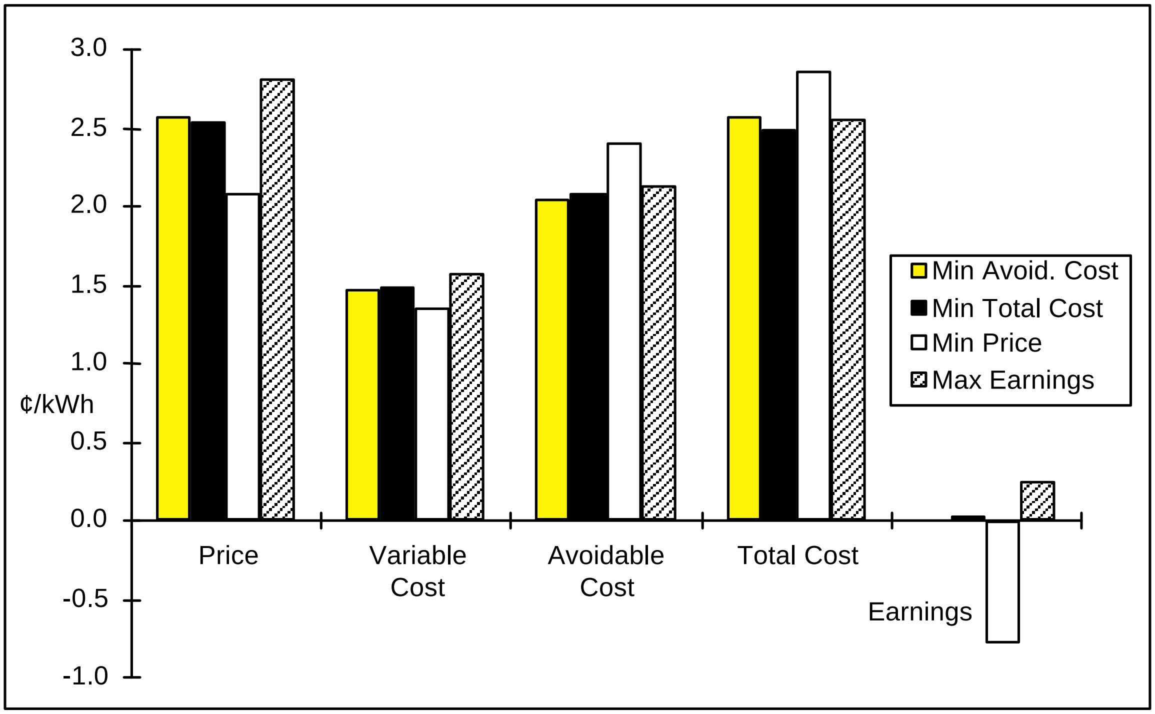
- Minimize total costs;
- Minimize avoidable costs (fuel, variable and fixed O&M);
- Minimize electricity prices; or
- Maximize generator earnings.

In Figure 6.2 we show the impact of different objective functions for optimization. Minimizing price does not necessarily minimize cost, because prices are based on the variable costs only and ignore fixed costs. Given choices of technology, ORCED would select low variable cost but high total cost technologies. Conversely, maximizing earnings does not raise total cost. Instead, the model selects high variable/low fixed cost technologies. For our analysis we chose to optimize on minimizing avoidable costs; we made this choice because it was conceptually the most appealing and the results were the most reasonable for a system-wide optimization. For plants not yet built, their capital costs as well as all operating costs are avoidable. Since no costs have been expended to build them, their construction costs are not "sunk" and can be avoided by not building them.

In addition to specifying the optimization function, the user can also specify constraints on individual generating units or the mix as a whole. For example, the user could set minimum and/or maximum capacity levels for each generator. Maximum levels could be specified for those units that were built earlier. Minimum levels could be specified for those units that must be available for policy reasons (e.g., renewable resources that might not be fully cost-effective but are deemed desirable from a broad societal perspective). Also, minimum levels for new plants may be specified to represent plants built between the current year and the study year. Otherwise, the model may choose not to build these intermediate plants, selecting only those with the most advanced technologies. Constraints could be specified for a minimum capacity reserve margin, for a maximum carbon emission allowance, or to ensure that each generating unit recovers at least its variable plus avoidable fixed costs, and so on.

Since ORCED is written in Microsoft Excel, there are several methods that can be used for optimization. The easiest is to use the built-in Solver tool. A single cell can be identified as the objective function to be minimized, and other cells can be identified as variables, with constraints placed on their values and/or other parameters within the spreadsheet. Since the problem is non-linear, Solver uses a Generalized Reduced Gradient method, running the model thousands of times searching for a solution. Another method, which is generally slower but avoids problems of local optima, is the use of genetic algorithms.

Figure 6.2 Generation Price and Costs Using Different Optimizations (10% Fixed Reserve Margin)



6.4 SCENARIOS FOR 2010

6.4.1 Calibration to EIA AEO97

Before analyzing the two end-use efficiency scenarios, we first calibrated ORCED results to those produced by EIA's NEMS model for 1995 and 2010. Unfortunately, reconciling the two sets of results to each other is difficult because of differences in the ways that the two modeling systems classify various costs (e.g., fuel, variable O&M, fixed O&M, and capital costs associated with generation) as well as EIA's inclusion of administrative and general (A&G) and customer service costs in the basic categories of generation, transmission, and distribution costs.[4] Because of these difficulties, our numbers do not always match the EIA numbers exactly.

This calibration ensures that the assumptions concerning the mix of generating units, fuel prices, customer demand, environmental regulations, and so on are consistent between ORCED and those developed by EIA. For example, both sets of results assume the continuation of current economic and environmental policies affecting the U.S. electricity industry. However, EPA's proposed regulations to tighten standards for emissions of nitrogen oxides and small particulate matter are reflected in neither the EIA nor the ORCED results.

We first developed a base case for the year 2010 that includes the same mix of generating units (in both capacity and energy) as that produced by EIA, with the same reserve margin (11%), as shown in Table 6.1. In addition to data from the AEO97, we used other data from EIA (EIA 1996b, EIA 1996c, EIA 1995), as well as data from the North American Electric Reliability Council (NERC 1996), the Electric Power Research Institute (EPRI 1993), and a compilation of various official databases by Resource Data International, Inc. (RDI 1996).

Table 6.1 Comparison of Year 2010 AEO97 and ORCED Estimates of U.S. Generating Capacity and Generation

	Percent of generating capacity		Percent of generation	
	EIA	ORCED	EIA	ORCED
Hydro+other renewables	13.4	11.3	9.6	9.2
Coal	35.0	36.9	50.1	50.8
Nuclear	10.2	11.1	15.8	15.5
Oil	3.2	3.1	1.5	0.1
Gas	38.3	37.6	23.0	24.4

ORCED analyzes the generation sector only; the model is silent with respect to the costs of transmission, distribution, and customer service. ORCED produces the following cost estimates for 2010, all expressed in 1995 dollars and adjusted upward by 1/0.93 to reflect the 7% T&D losses between the generator busbar and the customer meter:[5]

Fuel	1.35
Variable O&M	0.18
Fixed O&M	0.51
<u>Capital</u>	<u>1.00</u>
Total	3.04¢/kWh

We developed an estimate of the EIA capital cost of generation by subtracting estimates of the capital costs associated with transmission, distribution, and administrative and general (A&G) services from EIA's total capital cost:

$$[\underbrace{2.32}_{\text{Total}} - \underbrace{(0.52 + 1.46)}_{\text{(Trans + Dist)}} * 0.63 - \underbrace{0.08}_{\text{A\&G}}] = 1.00¢/\text{kWh.}^{6}$$

Our estimate of the EIA fuel cost is based on the sum of EIA's fuel cost plus 88% of its wholesale purchase cost:

$$(\underbrace{0.98}_{\text{Fuel}} + \underbrace{0.67}_{\text{Wholesale}}*0.88) = 1.57¢/\text{kWh.}^{7}$$

We used the ORCED estimates of fixed and variable O&M costs to impute a comparable (i.e., equal) value for EIA.

The net result is very close agreement between the ORCED and EIA scenarios for 2010 (Table 6.2). EIA's estimate of the total cost of generation (3.26¢/kWh) is 7% higher than the ORCED result (3.04¢/kWh). The ORCED cost is lower because ORCED dispatches fewer expensive oil-fired resources than does the EIA model (Table 6.1). These differences in dispatch and variable costs occur because ORCED dispatches generation nationwide and ignores transmission constraints. The close agreement between EIA and ORCED results, in spite of all the adjustments required to produce a set of internally consistent and comparably defined terms, is reassuring. It lends confidence to our development of alternative cases in which we intended to reflect more fully than EIA did the effects of competition in bulk-power markets.

Table 6.2 Comparison of EIA and ORCED Estimates of Generation Costs (1995¢/kWh)

Generation costs	EIA AEO97	ORCED
Capital	1.00	0.99
Fuel	1.57	1.36
O&M	0.69	0.69
Total	3.26	3.04

6.4.2 The Base Case for a Competitive Market

Beginning with the AEO97 case, we developed a case intended to reflect the workings of a fully competitive bulk-power market in the year 2010. (The AEO assumes a continuation of current economic regulation, as indicated above, and therefore does not account for the possible effects of a restructured and largely competitive U.S. electricity industry.) To reflect these changes, we let the model select the amounts of each of the generating units that minimize the sum of variable plus avoidable costs. Instead of specifying the amount of generating capacity that must be online in 2010 (to yield a 10.7% reserve margin in the AEO97 case), we allowed the model to select the amount of capacity that minimized the cost of the power-supply system plus the cost of unserved energy. We used a demand elasticity of -0.05 for those time periods when capacity is insufficient to meet unconstrained demand. The resultant optimization yielded a reserve margin of 6.8%.

In general, we set prices equal to their real-time (hourly) values based on the variable (fuel plus variable O&M) cost of the unit on the margin each hour of the year, adjusted overall electricity demand to reflect lower prices using an assumed overall elasticity of -0.5, and adjusted the load shape to reflect the response to real-time pricing using a value of -0.1 for the price elasticity within each time period.

Beginning with the ORCED run that matches the AEO97 values for 2010, we first reran the model allowing it to select the "optimal" amounts of generating capacity from among all the plants that, according to EIA, are scheduled to come online after the year 1998. (The optimization was based on a minimization of avoidable costs.) We also allowed the model to select plants for retirement. For each of the new plants, we use the levelized fixed charges rate to calculate the annual capital cost of the plant and treat all fixed costs (both capital and O&M) as avoidable.

Next, we adjusted the load-duration curves for the two seasons simulated by the model (peak and off-peak). The new system load has a peak demand that is 3.4% below the AEO97 case and a total demand that is 1.2% higher. We then reran ORCED using the new load shapes. Table 6.3 compares the two sets of results. Although demand is higher in the restructuring case than in the AEO97 base case, carbon emissions are lower. The lower carbon emissions are the result of reduced coal use and increased natural gas use in the restructuring case.

Notice that, under restructuring, the total generating cost goes down 0.3¢/kWh and yet the system average price increases slightly. In a deregulated market, prices will be based on the variable cost (or bid price) of the most expensive plant at that time. This is known as the "market clearing price." Consequently, the link between total costs and prices is broken. Whereas current electric utility regulation sets prices to recover total costs, future prices may, or may not, be sufficient to recover all costs.

Overall, ORCED prices under restructuring did not differ greatly from the AEO97 price forecast. Part of the reason for this similarity of results is that EIA did assume some cost decreases in their model; we did not assume further O&M cost decreases on a plant-by-plant basis due to the pressure of competition. Also, the objective function used in our cases was to minimize avoidable costs on a system-wide basis. This did not necessarily create the lowest-priced scenario, as discussed in section 6.3. Because prices were similar to those in the AEO97 (less than 5% difference when factoring in transmission and distribution prices), we simply used the AEO97 price forecasts for analysis of energy-efficiency savings in the other chapters of this report.

Table 6.3 Comparison of Year 2010 Forecasts: AEO97 and the ORCED Base Case for a Competitive Electricity Industry

	AEO97	Competitive Industry Restructuring
Peak demand, GW	734	709
Total end-use electricity sales, TWh	3,784	3,828
System load factor, %	62.8	65.7
Reserve margin, %	10.7	6.8
Generation shares, %		
Coal	50.8	47.4
Gas	24.4	29.2
Other	24.8	23.4
Generation prices and costs, ¢/kWh		
Retail price	3.04	3.02
Variable cost	1.43	1.45
Total cost	2.81	2.51
Carbon emissions, MtC	631	625

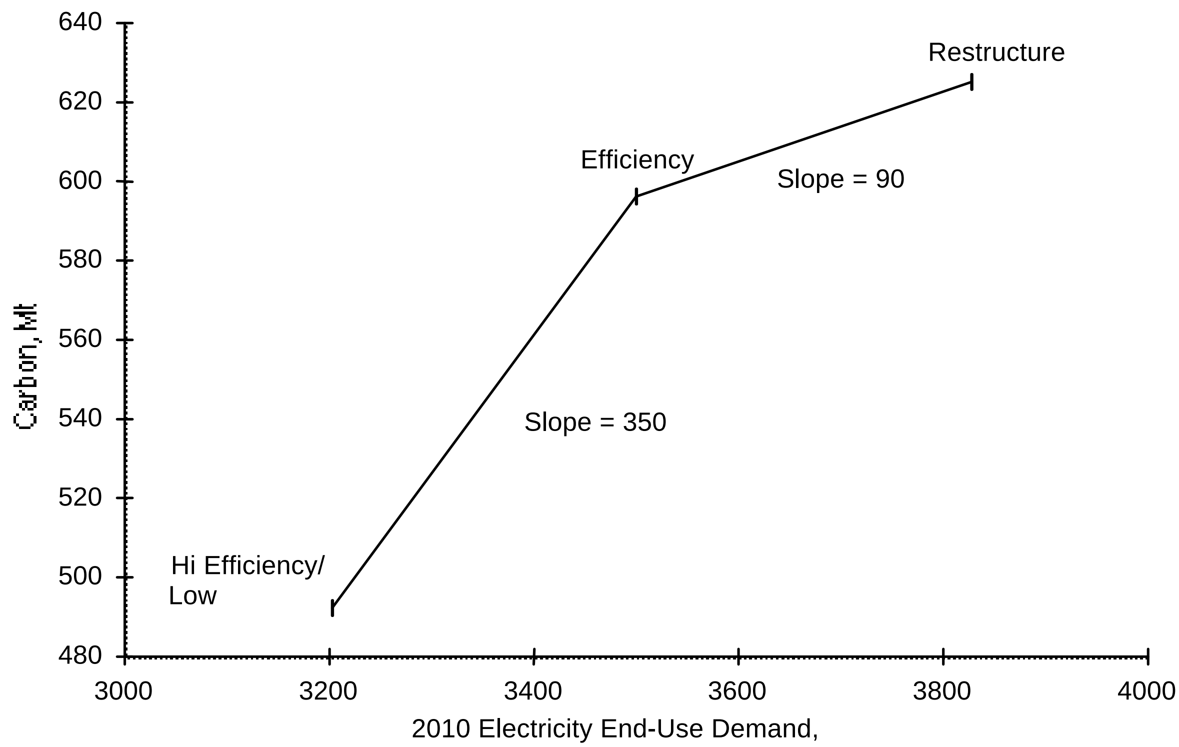
6.4.3 Efficiency and High-Efficiency/Low-Carbon Cases

We next applied the electricity-savings estimates, described in Chapter 3 for the residential and commercial sectors and in Chapter 4 for the industrial sector, to adjust the aggregate load shape for the United States as a whole. We then reran ORCED using the new, lower load shapes. As in the reference case, capacity was optimized to minimize avoided costs, and dispatched on the basis of lowest variable costs. Avoided costs for existing plants only included their variable, start-up, and fixed O&M costs, while plants to be built between 1997 and 2010 also included the annualized capital cost of their construction. As part of the high-efficiency/low-carbon case, we included an additional cost of $50 per tonne of carbon, to be consistent with the rationale used in the demand-side efficiency scenarios.

Once power plant production levels were determined, carbon production and primary energy use could be calculated. We calculated marginal carbon savings, the carbon saved by the reduction in energy, by taking the difference in carbon production and dividing by the reduction in energy demand. This is in contrast to using the average carbon intensity as an approximation of the carbon saved per unit of energy saved. The marginal carbon and energy savings take into account the change in production mix that occurs with energy- efficiency and carbon-reduction measures. A plot of the carbon savings and primary energy used in each scenario shows the changes as a function of the end-use energy saved (Figures 6.3 and 6.4). The slopes of the lines represent the marginal carbon and primary energy saved.

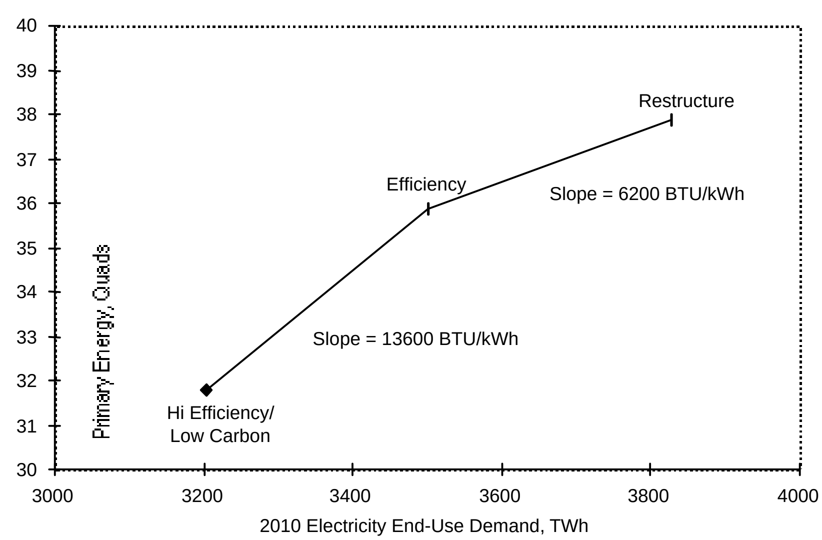
Table 6.4 summarizes the results for the three scenarios. Table 6.5 describes these results in terms of percent change relative to the base case for a competitive utility industry. The efficiency case yielded a 8.5% reduction in electricity end-use energy and the high-efficiency/low-carbon case reduced end-use energy by 16.3% relative to the restructuring case summarized in Table 6.3.

Figure 6.3 Carbon Production Versus End-Use Demand: Reductions Due to Energy Efficiency and Carbon Management



Note: Slope is equal to marginal carbon savings in tonnes of carbon per gigawatt-hour.

Figure 6.4 Primary Energy Production Versus End-Use Demand: Reductions Due to Energy Efficiency and Carbon Management



Note: Slope is equal to marginal energy savings in Btu per kilowatt-hour.

Table 6.4 Comparison of Year 2010 Forecasts: Results of Efficiency and High-Efficiency/Low-Carbon Scenarios

	Competitive Industry Optimization	Efficiency	High-Efficiency / Low-Carbon
Peak demand, GW	709	651	596
Total Primary Energy used, quads	37.9	35.9	31.8
Total electricity generated, TWh	4,090	3,740	3,420
Total end-use electricity demand, TWh	3,830	3,500	3,200
System load factor, %	65.7	65.5	65.5
Reserve margin, %	6.8	7.9	12.9
Generation shares, %			
Coal	47.4	52.1	46.2
Gas	29.2	22.2	26.0
Other	23.4	25.7	27.8
Generation prices and costs, ¢/kWh			
Retail price	3.02	3.03	3.66
Variable cost	1.45	1.43	2.07
Total cost	2.51	2.46	3.21
Carbon emissions, MtC	625	596	492
Average carbon emissions, kg/MWh	163	170	154
Marginal carbon saved, kg/MWh	–	89	350

Table 6.5 Comparison of Year 2010 Forecasts: Effects of Efficiency and High-Efficiency/Low-Carbon Scenarios

	Change relative to the competitive utility industry base case	
	Efficiency	High Efficiency / Low Carbon
Peak demand	-8.2%	-16.0%
Total energy	-8.5%	-16.3%
System load factor	-0.2% points	-0.2% points
Reserve margin	+1.1% points	+6.1% points
Generation shares		
Coal	+4.7% points	-1.2% points
Gas	-7.0% points	-3.2% points
Other	+2.3% points	+4.4% points
Generation prices and costs		
Retail price	+1%	+21%
Variable cost	-1%	+43%
Total cost	-2%	+28%
Carbon emissions	-4.6%	-21.2%

The efficiency scenario forecasts a lower percentage reduction in carbon (4.6%) than in end-use energy (8.5%) (Figure 6.5). The difference occurs because lower end-use demands translate into less construction and operation of high-efficiency gas-fired combustion turbines and combined-cycle units (Figure 6.6). (Because of their high capital costs, ORCED selects only the minimum amounts of advanced coal and renewable technologies in the base restructuring case.) In the efficiency case, relative to the restructuring case, capacity and generation for combined-cycle units declines by about 27%; capacity for combustion turbines drops 28% (generation drops by 68%); and coal and gas-powered steam plants actually increase their production slightly.

Identification of high-efficiency gas-fired combustion turbines and combined-cycle units as the marginal plants under consideration has the effect of substantially lowering the avoided carbon from electric efficiency improvements. The forecasts contained in AEO97 are consistent with this assumption through the year 2010. For example, page 49 of the AEO97 states that, “of the new capacity [required through 2015], 81 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas.”

In contrast, the HE/LC case forecasts a higher percentage reduction in carbon (21.2%) than in end-use energy (16.3%). This is because the inclusion of the charge of $50 per tonne of carbon changes the mix of technologies used to produce electricity so that low-carbon supply options are favored. Over 16% of the coal capacity is retired in this scenario, and the remaining, more-efficient coal plants operate at a lower capacity factor. Overall, generation from coal declines 18% compared to the reference case. Capacity from combined cycle plants actually increases over the amount in the efficiency case, but still has a 14% decline from the reference case. Combustion turbine generation declines 84% from the reference case while combined cycle generation declines only 13%.

Figure 6.5 Energy and Carbon Changes from Restructure Case

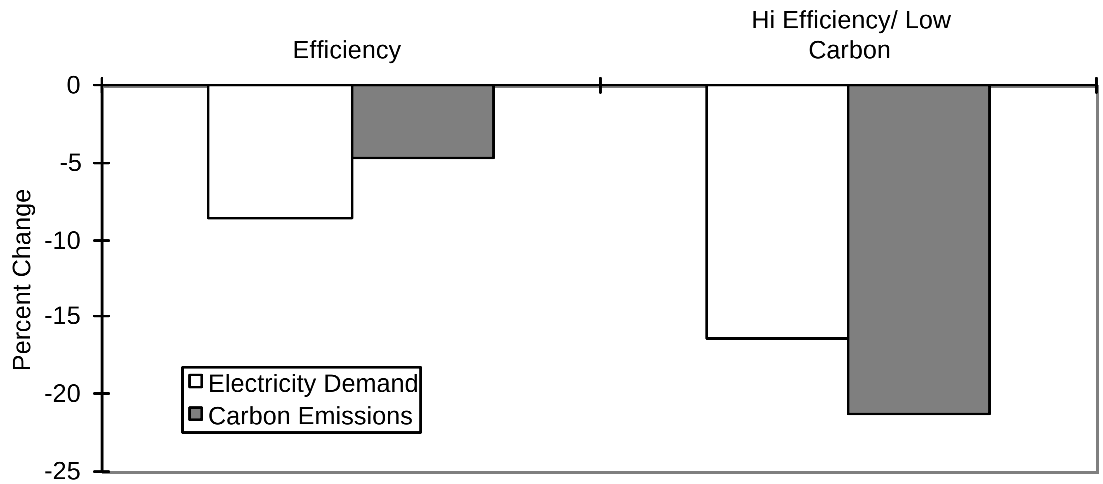
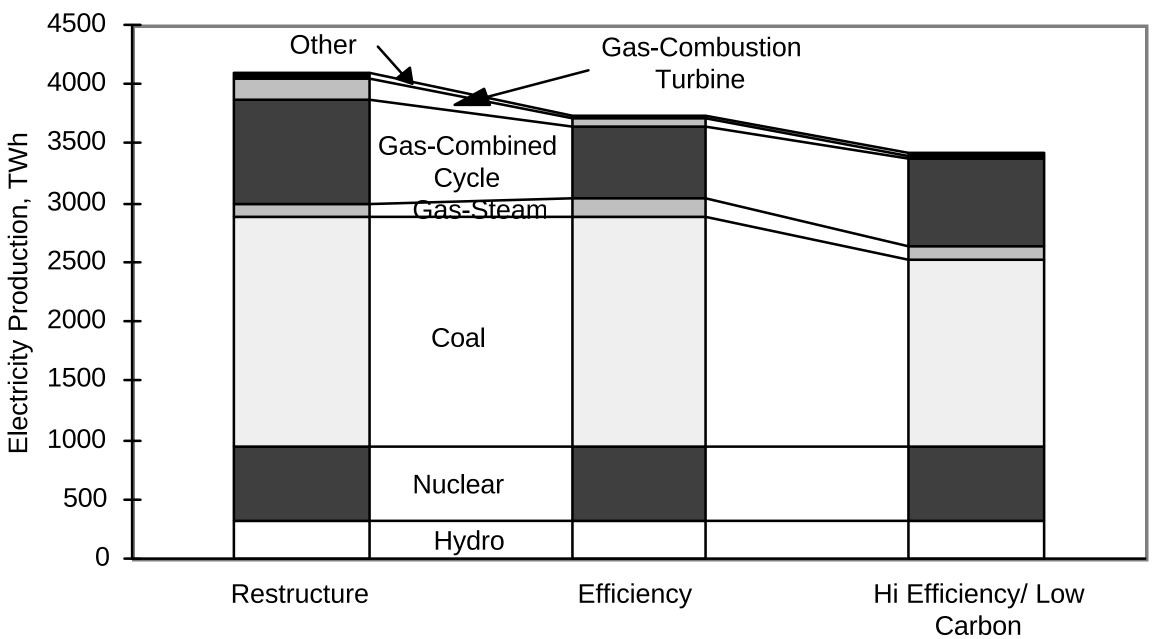


Figure 6.6 Generation by Technology Under Each Scenario



Compared to the reference case, generating prices and costs remain about the same under the efficiency scenario. In the HE/LC scenario, prices and costs increase about two-thirds of a cent because of the additional charge of $50/tonne of carbon. This carbon charge represents a 1.4¢/kWh increase to the more expensive coal plants, but only a 0.5¢/kWh increase to the better gas-fired combined cycle plants. ORCED redispatched and changed capacities so that the cost increase would be minimized. Note that, although the generation price increases by 21%, the price of generation represents only about half of the total price of electricity. Keeping transmission, distribution, and customer service prices the same, the total price increase would be only 10%.

Because electricity prices are essentially unchanged under the efficiency scenario (changing from only 6.20¢/kWh to 6.22¢/kWh including other components), total electricity costs to consumers decrease by an amount that is proportionate to the reduced electricity demand (i.e., 330 TWh). Thus, the cost reduction is approximately $20 billion. This value takes into account the savings in transmission, distribution, and customer service costs included in the full retail price of electricity. The high-efficiency/low-carbon case yields slightly lower savings of around $18 billion. Total energy savings almost double to 630 TWh, but the price increase of 0.65¢/kWh due to the carbon charge cuts into the overall savings.

One way to measure the cost impact of the $50/tonne of carbon cost is to evaluate the extra cost due to plant operation changes (redispatch, retirements, and new construction). In the high-efficiency/low-carbon case, we construct and operate the plants as optimized with the carbon charge. If we remove the charge, but construct and dispatch plants as in the high-efficiency/low-carbon case, we are no longer operating at minimum cost. The excess above the minimum cost is about $2.2 billion. Dividing this amount by the tons of carbon saved from the minimum-cost case yields an average cost of $30 per tonne of carbon saved.

Allocating the carbon savings in the efficiency case between the buildings and industrial sectors, we find that the buildings sector (residential and commercial) saved 19.4 Mt of carbon while the industrial sector saved 9.6 Mt (Table 6.6). The carbon savings for each were proportional to their savings in electricity, since electric generation is determined by the system load.

Table 6.6 Carbon Reductions from Electricity Savings by Sector under the Efficiency and High-Efficiency/Low-Carbon Cases (MtC)

Sector	Efficiency Case	High-Efficiency/Low-Carbon Case
Buildings (Residential)	10.9	49.2
Buildings (Commercial)	8.5	38.3
Industry	9.6	45.0
Total	29.0	132.5

Note: Transport is not included since electricity use in that sector is negligible.

Some of the 133 Mt of carbon that is forecast to be displaced by the high-efficiency/low-carbon case can be attributed to the end-use efficiency improvements in the buildings and industrial sectors. The remaining savings are attributed to the change in electricity generation mix that resulted from the charge of $50/tonne of carbon. Two methods of allocating the carbon savings between the end-use and supply sectors were examined.

- In the first method, ORCED modeled the high-efficiency/low-carbon case without the $50/tonne charge in the supply sector. The result was a savings of 56 MtC, attributed to energy efficiency alone. The rest of the carbon savings (77 MtC) is then attributed to the electricity sector.

- In the second method, ORCED modeled the restructure case with the $50/tonne charge in the supply sector, but without the demand reduction due to efficiency improvements. The result was a savings of 33 MtC, which is attributed to the electricity sector. The rest of the carbon savings (100 MtC) is attributed to the end-use sectors based on their energy savings.

The results of these alternative allocations (including the distribution of carbon savings across the buildings and industrial sectors) are shown in Table 6.7 and Figure 6.7. The total carbon that is displaced by the lower electricity demand is the same (133 MtC), but the allocation between the end-use and supply sectors varies widely depending on the method used to allocate the savings.

Because the savings involve a synergy between increased energy efficiency and changes to supply dispatching, it is difficult to identify the appropriate allocation of savings for the end-use vs. electricity supply sectors. To simplify matters, we used the average between the two methods described above. Specifically, the following averaging was used:

The minimum carbon reduction attributed to electricity end-use efficiencies is 56 MtC (Method 1) and the maximum is 100 MtC (Method 2). The average of 78 MtC is therefore assumed for the end-use sector.

The minimum carbon reduction attributed to the electricity sector is 33 MtC (Method 2) and the maximum is 77 MtC (Method 1). The average of 55 MtC is therefore assumed for the electricity supply sector.

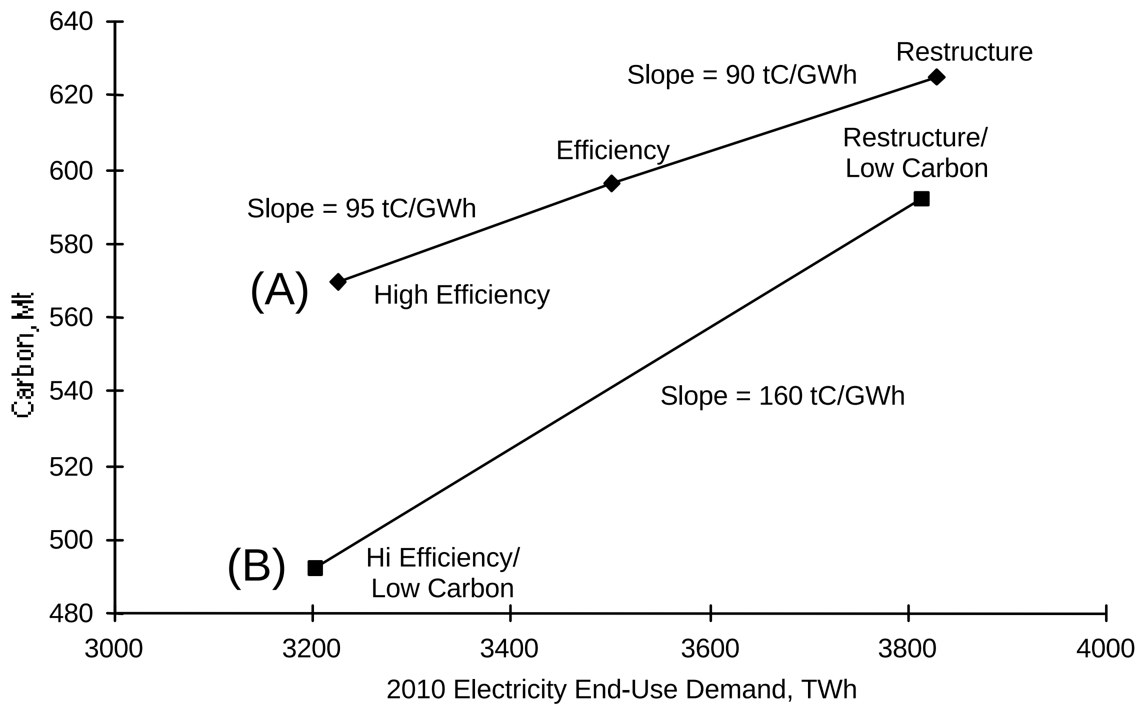
Table 6.7 summarizes this allocation process.

Table 6.7 Allocation of Carbon Reductions from the Electricity Saved by the High-Efficiency/Low-Carbon Case (MtC)

Sector	Method 1: Carbon Reduced by Energy Efficiency First	Method 2: Carbon Reduced by $50/tC Charge First	Final Allocation by Averaging
Buildings (Residential)	21	37	29
Buildings (Commercial)	16	29	22
Industry	19	34	27
Subtotal	56	100	78
Electricity Sector	77	33	55
Total	133	133	133

Based on the results shown in Figure 6.7, 160 tonnes of carbon are displaced for each GWh of electricity saved in the high-efficiency/low-carbon case with carbon permit price of $50/tonne, reflecting the introduction of new low-carbon technologies. This is the marginal carbon-to-energy ratio that is therefore used for analyzing the impacts of other carbon management strategies in the electricity sector in Chapter 7. This value is significantly higher than the marginal carbon-to-energy ratio used in the efficiency case (90 tonnes of carbon per GWh of electricity, as also shown in Figure 6.3), for the reasons noted earlier.

Figure 6.7 Carbon Reductions Due to Energy Efficiency and Carbon Management: (A) Without a Carbon Charge and (B) With a Carbon Charge of $50/Tonne



Note: Slope is equal to marginal carbon savings in tonnes of carbon per gigawatt-hour. In (A), the high-efficiency option represents all the assumptions of the high-efficiency/low-carbon scenario except that there is no charge for carbon.

6.5 SUMMARY

The U.S. electricity industry is undergoing massive change. Because the process is far from complete, it is even more difficult to make estimates about electricity production and use for the year 2010 than it would otherwise be. However, we developed a reasonable and internally consistent picture of electricity demand and supply for the year 2010 on the basis of EIA's AEO97 projection and additional simulations with the Oak Ridge Competitive Electricity Dispatch (ORCED) model.

ORCED was used to simulate the operation of the U.S. electric power supply system in 2010. We first calibrated our input data so that our results closely matched those produced by EIA for its *Annual Energy Outlook 1997*. We then developed a case for 2010 that is intended to reflect the ways in which a fully competitive industry might operate. Compared to the AEO97, these results suggest greater electricity use, lower peak demand, and a generation mix that includes more natural gas and less coal. Thus, although consumption is higher, carbon emissions are lower.

We then simulated the operation of this competitive electricity industry given the efficiency-induced reductions in electricity use in the residential, commercial, and industrial sectors as described in Chapters 3 and 4. The efficiency case reduced electricity demand by 9%, which led to a 5% reduction in carbon emissions. The high-efficiency/low-carbon case reduced electricity use by 16%, which led to a 21% reduction in carbon emissions.

6.6 REFERENCES

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ENDNOTES

[1] States will continue to oversee power-plant siting and environmental emissions.

[2] The value of unserved energy is the price that customers would be willing to pay for electricity that is unavailable as a result of demand exceeding supply.

[3] The amount of computer time required for a full simulation depends strongly on the number of generators treated probabilistically. We found a reasonable tradeoff between computing time and accuracy when about 10 plants are modeled probabilistically and the other 16 are derated.

[4] Inclusion or exclusion of the data for cogenerators (which account for about 4% of electricity in the year 2010) is another source of confusion.

[5] According to AEO97, total generation in 1995 was 3246 billion kWh and sales totaled 3008 billion kWh, implying a loss of 7.3%.

[6] The 63% multiplier for T&D represents the percentage of T&D costs attributable to capital as opposed to O&M.

[7] This 88% multiplier is derived from ORCED's estimates of fuel and O&M costs of 1.35¢/kWh for fuel and 0.18 ¢/kWh for O&M. The 88% then is [=1.35/(1.35+0.18)].